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SENSITIVITY ANALYSIS OF DUAL-PERMEABILITY SYSTEMS

Laurence C. Hull and Tom M. Clemo

Hydrology Unit
Idaho National Engineering Laboratory

ABSTRACT

The substitution of matrix permeability for fracture permeability to simplify the simulation of complex fracture systems requires a radically different treatment of transport in the matrix. The spatial distribution of pressure is reasonably well described by inclusion of only the major fractures. Transport of tracer and heat, however, depends on a detailed knowledge of fluid velocities. These velocities are dependent on the active porosity of the system. Because fractures channel flow, the active porosity may be much smaller than the total porosity of the system. Characterization of this active porosity is necessary to quantify tracer and heat movement.

INTRODUCTION

Simulation of complex geothermal reservoirs is frequently accomplished by substituting matrix permeability for fracture permeability. This results in a saving of computer resources and permits the simulation of larger and more complex fracture systems. The substitution of a continuum to represent fracture permeability involves a number of assumptions which must be evaluated. Development of continuum properties for representation of discrete fracture systems is an area of active research. Studies have been conducted by Clemo (1986), Dershowitz (1984), Endo et al., (1984), Long and Witherspoon (1985), and Schwartz and Smith (1983).

The more intersections between fractures in a fracture network, the more the system is likely to behave as a porous medium. On a large scale (reservoir scale) an equivalent hydraulic response can be obtained by using an appropriate hydraulic conductivity. Transport depends on a detailed knowledge of fluid velocities, not just fluxes. As a result, the pore volume of the system involved in the movement of water must be well characterized. One method of treating transport is through the development of an active porosity. The active porosity may be much less than the total porosity of the system due to fracture orientation and preferred flow paths.

A dual-permeability model was used to study the effects of replacing fracture permeability with matrix permeability. The dual-permeability approach is uniquely qualified for this type of study because the replacement can be performed gradually so that the cumulative effects can be evaluated. This paper illustrates the effects of replacing discrete fracture permeability with matrix permeability on spatial pressure distribution and tracer transport. The effects on heat transfer are also considered.

CODE DESCRIPTION

The study was conducted using the FRACSL code developed at the Idaho National Engineering Laboratory (Miller, 1983; Clemo and Hull, 1986). The code simulates flow in porous matrix blocks and discrete, parallel sided fractures. Transport processes included are advection, diffusion, dispersion, and diffusion from the fracture into the surounding matrix. For this study, simplified heat transport capabilities were added to the code. Heat transport by advection and conduction are computed. All boundaries are considered perfect insulators and there is no coupling of flow with thermal effects.

SYSTEM DESCRIPTIONS

The system studied consists of an injection and a production well in a geothermal reservoir 1200 m long and 90 m high. The simulation is two-dimensional and a slice of unit thickness through the reservoir assumed. Fluid properties used were those for 175^{o}C. Six variations were simulated. The base system is a fracture network consisting of 22 fractures (Figure 1). Three

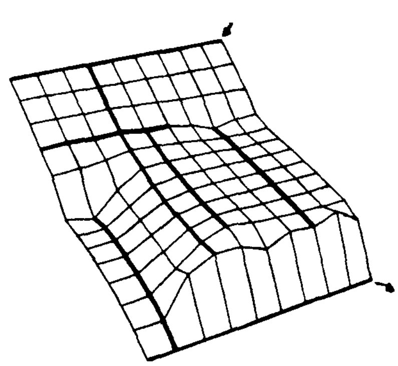
Table 1. Summary of characteristics of the six dual-permeability systems simulated.

System	Description	Number of Fractures	Connecting Paths	Hydraulic Conductivity (m/day)	Active Pore Volume (%)
1	Matrix only	0	0	7.9	108
2	No fracture connection between wells	5	0	0.78	78
3	One cross connection between wells	10	4	0.42	36
4	Several connections between wells	14	12	0.18	44
5	Full network	22	21	0.009	40
6	Single fracture	1	1	0.009	16

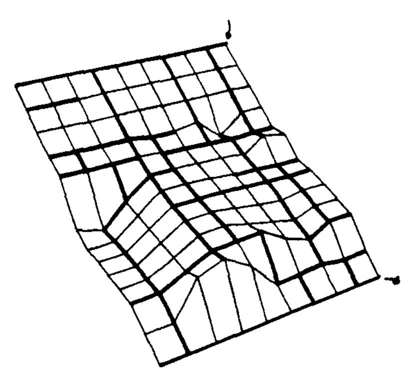
additional fracture networks were derived from the base system by removing fractures from the system, starting with the smallest fractures. This created four fracture systems of differing complexity. A fifth system was created which consists entirely of porous matrix. The sixth and final system is a single fracture connecting the injection and production wells.

System 5 was defined as the base case and the other systems were derived from System 5. Table 1. shows the characteristics of the six systems. All the systems have the same effective hydraulic conductivity. For the same steady-state injection and production rates, the pressure difference between injection and production wells is identical. This is accomplished by increasing matrix permeability as fractures are removed from the system. For System 6, the matrix permeability was set equal to that for System 5 and the aperture of the single fracture adjusted until the pressure difference matched that of System 5.

The porosity of the fracture system, calculated by dividing the volume of fractures by the total volume of the reservoir, is 10^{-4}. Therefore, the matrix porosity of the systems was set to 10^{-4} to mimic that of the fracture system. This small matrix porosity was used so that the matrix flow rates would be similar to flow rates in the fracture system. One consequence of this very small matrix porosity is that diffusion of tracer into the matrix is essentially prevented. Tracer can, however, advect into the matrix for the systems with significant matrix permeability.



System 2, No fracture connections



System 5, Full fracture network

Figure 1. Steady-state pressure distributions for dual-permeability fracture networks. The networks are shown as darker lines on the grid representing the pressure distribution.

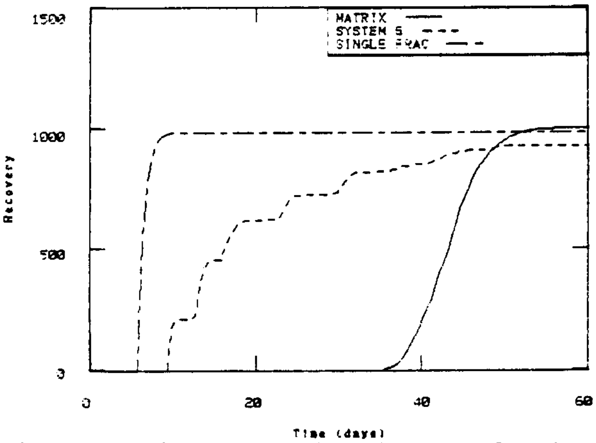


Figure 2. Tracer breakthrough curves for the single fracture, full fracture network, and the porous matrix representation of the geothermal reservoir. One-thousand particles were injected.

The active pore volume shown in Table 1 is the ratio of pore volume calculated from tracer breakthrough to total system pore volume. Tracer breakthrough pore volume is calculated from the volume of fluid which had been pumped at the time 50% of the injected tracer had been recovered. For the single fracture representation of the reservoir, only a very small volume of the system is actively involved in solute transport. For the porous matrix representation, the entire system participates in solute transport. The various fracture systems have an intermediate value for active porosity.

SIMULATION RESULTS

Simulations for each of the six systems provided steady-state pressure distribution, tracer breakthrough, and distribution of the thermal front.

Pressure Distribution

The steady-state pressure distribution for Systems 1 and 6 showed a uniform, featureless pressure decline from the injection well to the production well. The fracture networks, however, showed spatial variations in pressure due to the distribution of fractures. The spatial variations in pressure are very similar for all of the fracture networks (Figure 1). This indicates that only the largest, most significant fractures need be included in a simulation to obtain a reasonable estimate of spatial pressure distribution. As a result, the general distribution of flow in the systems should be fairly similar. This similarity requires replacing the smallest fractures with matrix and explicitly simulating the larger fractures. The more dominant effects of the major fractures must be retained.

Tracer Transport

The method of representing permeability has a tremendous effect on tracer transport. Figure 2 shows tracer breakthrough for Systems 1, 5, and 6. The concept of active porosity is most easily demonstrated with this figure. For the single fracture, all fluid moves along a single path which encompasses a very small volume of the reservoir. As a result, tracer breakthrough occurs rapidly and is distributed over a very short time interval. On the other hand, the entire volume of the reservoir is swept by the tracer when a porous matrix representation is used. Thus the active porosity is a maximum, and the arrival of the tracer takes the longest time. Because flow is uniformly distributed over the reservoir, the distribution of arrival times is very clustered, and the breakthrough curve is fairly steep.

For the fracture network, an intermediate breakthrough curve is obtained. Some tracer arrives fairly rapidly, moving along the most direct discrete fracture pathway. Other tracer moves along less direct pathways and takes a longer time to arrive at the production well. Because of the wide distribution of flow rates in the many fracture flow paths, the distribution of tracer arrival times is very broad.

Breakthrough curves are more similar for the three systems where a fracture connection between the injection and production wells was retained (Figure 3). Small differences exist due to the number of connecting paths and the replacement of discrete fracture pathways with porous matrix. The general shape of the breakthrough curves is similar because most of the tracer still travels through the fracture system. The tail on the breakthrough curves for Systems 3 and 4,

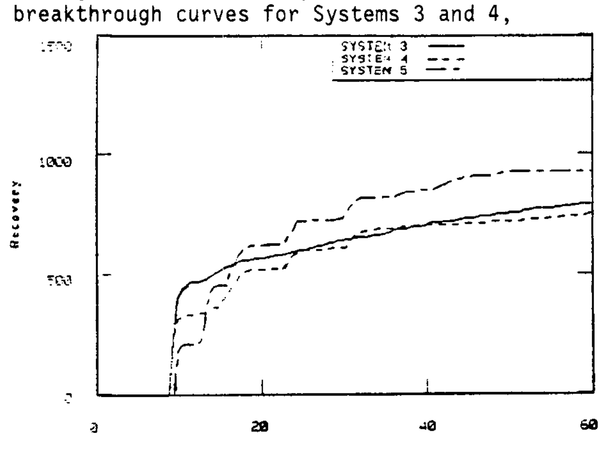


Figure 3. Tracer breakthrough curves for three fracture networks which retain a discrete connection between the injection and production wells but which have different matrix conductivity.

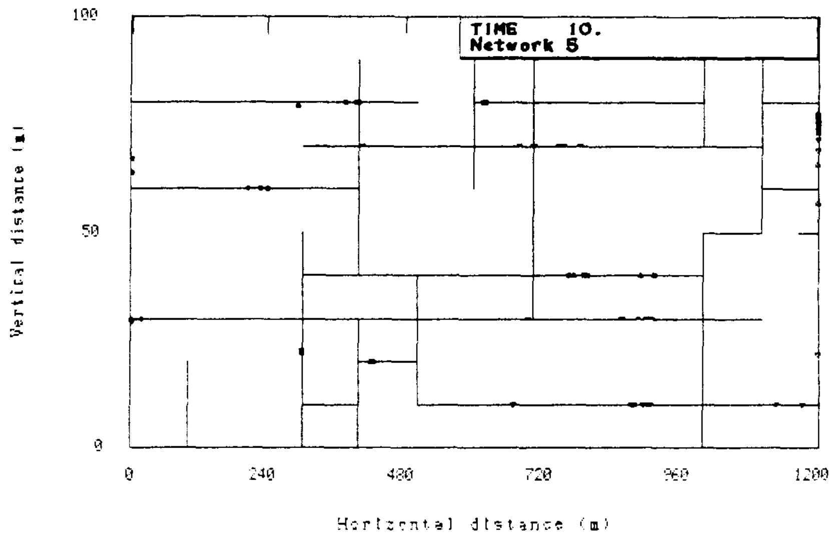


Figure 4. Spatial distribution of tracer remaining in System 5 at 10 days.

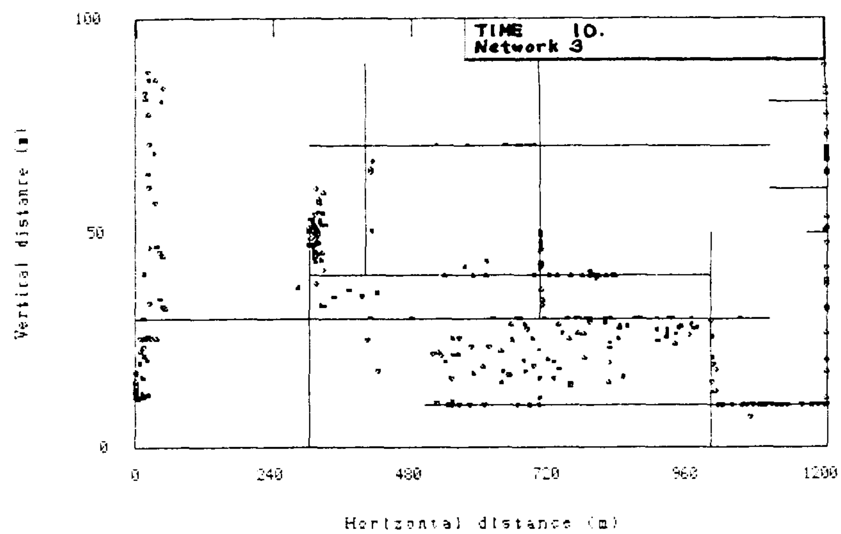


Figure 5. Spatial distribution of tracer remaining in System 3 at 10 days.

however, is much longer than the tail for System 5. This is because significant matrix permeability in Systems 3 and 4 results in tracer entering the matrix. Even though the matrix porosity is 10^{-4}, there is a significant increase in the residence time of tracer in the reservoir. Thus, simply using a matrix with a small porosity to represent fractures may not be sufficient.

The increase in active porosity is shown by comparison of Figures 4 and 5. These figures show the spatial distribution of tracer 10 days into the injection test. For System 5 (Figure 4), the tracer has remained in the fractures and the matrix does not participate in the movement of tracer. Figure 5 shows the distribution of tracer for System 3, which has significant matrix permeability relative to System 5. In this case, tracer moves from the fractures through the matrix. This matrix increases the residence time of the tracer that travels by these paths.

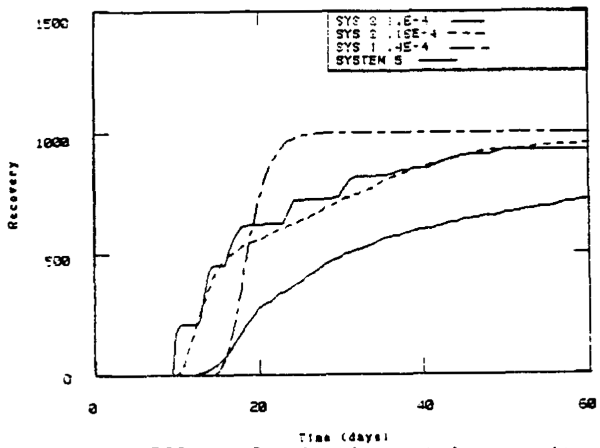


Figure 6. Effect of adjusting matrix porosity to match active porosity estimates on tracer breakthrough.

The effect of fractures on channeling flow through the system can be seen in Figure 5. Tracer is not uniformly distributed throughout the matrix, but is confined to matrix in a few areas between fractures. The rate of tracer movement is not dependent on the pore volume of the entire reservoir, but on the porosity of a fraction of the reservoir. This fraction of the reservoir which is actively involved in the transport of tracer is the active porosity. The active porosity for this reservoir is on the order of 40% for tracer transport (Table 1).

When fracture permeability was replaced with matrix permeability, the active porosity of that part of the system was increased. Based on the results from System 6, a single fracture has an active porosity 0.16 times the total porosity. As most matrix blocks

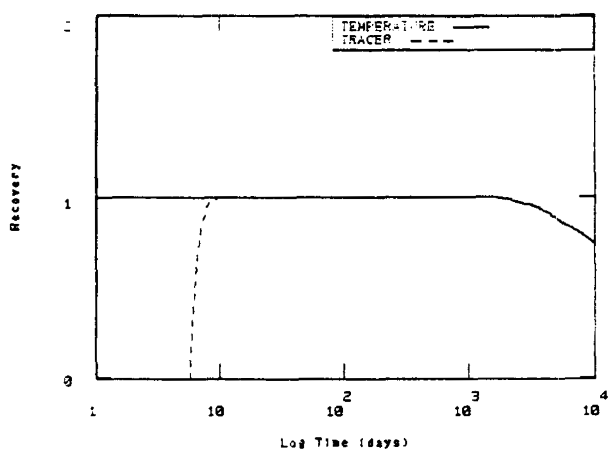


Figure 7. Comparison of tracer and thermal breakthrough for a single fracture connecting an injection and production well.

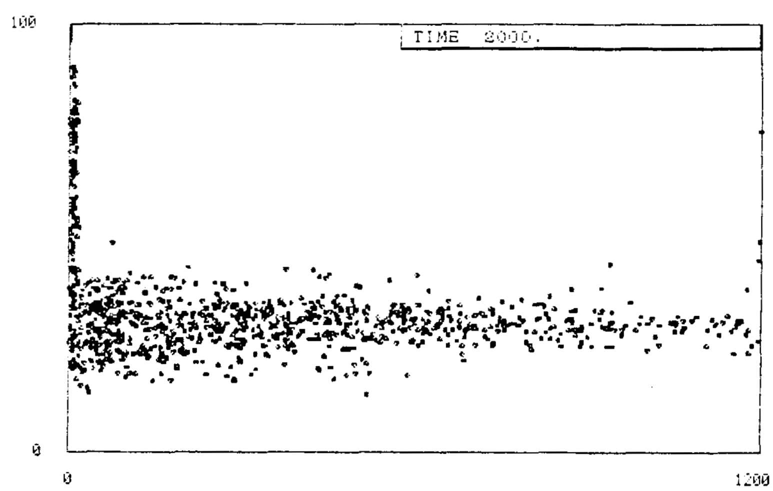


Figure 8. Spatial distribution of cooling in the geothermal reservoir at 2000 days due to injection for flow through a single fracture. Vertical spreading of the thermal front is exagerated by a factor of 7.4.

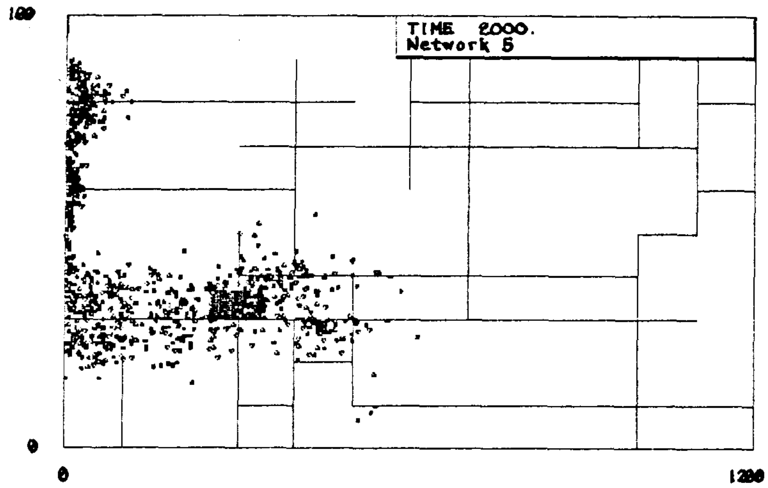


Figure 9. Spatial distribution of cooling in the geothermal reservoir at 2000 days due to injection in the fracture network.

represent the replacement of a single fracture, using a matrix porosity of $1.0X10^{-4}$ may overestimate the active porosity by a factor of 6.25. System 2 was resimulated using a value of $0.16X10^{-4}$ for the matrix porosity to determine if the active porosity did a better job of emulating the full network. The active porosity for the entire reservoir, based on Systems 3, 4, and 5, is on the order of 40%. System 1 was resimulated using a porosity of $0.4X10^{-4}$ to match the active porosity of the fracture networks.

Figure 6 shows the effects of using the active porosity to simulate transport in the matrix rather than the total porosity. Using an active porosity of $0.16X10^{-4}$ in System 2 resulted in a tremendous improvement in matching the response of the full fracture network. Using an active porosity for the full matrix representation improved the match to the mean arrival time, but the breakthrough curve has the wrong shape. Too much information on the flow system was lost when all the fracture permeablitity was replaced with matrix permeability. When the major fractures were explicitly considered, sufficient information on the flow system remained to achieve a good match between the full fracture system and a system where most of the fracture permeability had been replaced with matrix permeability.

Thermal Response

As used for these simulations, the code does not take into account the effects of density differences between fluids. Simple calculations indicate that density differences can induce pressure differences as large or larger than those developed from the flow alone. Therefore, the results presented here are more applicable to the phenomenon of heat conduction from the fracture to the matrix than for reservoir scale transport.

The time required for the system to respond thermally is much greater than the time required for the system to respond to tracer injection. This difference is attributable to two differences between tracer and heat. Diffusion of tracer into the matrix is dependent on the open porosity of the matrix and on the diffusion coefficient of the tracer. Both these numbers are very small. The diffusion of heat into the matrix (conduction) is dependent on the heat capacity of the matrix and on the thermal diffusivity of the rock. These number combine to give a factor about three orders of magnitude greater for thermal conduction than for tracer diffusion.

Figure 7 shows the difference in time for tracer breakthrough and thermal breakthrough to occur for the single fracture. The time scale is logarithmic to accommodate the large difference in breakthrough times. Figure 8 shows the portion of the reservoir that has cooled at a time 2000 days after injection began. Only a small fraction of the reservoir is participating in the reheating of the injected fluid. Figure 9 shows the portion of the reservoir that has cooled after 2000 days for the full fracture system. The cooling front has moved only about one-third of the distance across the reservoir. This shows that the front will progress at a rate roughly proportional to the active porosity of the reservoir. The active porosity of System 5 is about 2.5 times the active porosity of System 6. If this is indeed the case, then the information on active porosity obtained from tracer testing will be very applicable to prediction of thermal breakthrough.

For the porous matrix representation of the reservoir, System 1, the thermal front progresses very slowly away from the injection well. This slow rate of movement is due to the complete extraction of heat from the reservoir rock. Use of the porous matrix representation of the reservoir would greatly overestimate the time for thermal breakthrough to occur.

CONCLUSIONS

Simulations were conducted of six representations of a geothermal reservoir. The systems differed with respect to the number of fractures, the connectivity of the fracture system, and the permeability of the matrix material. Steady-state pressure response and tracer breakthrough were calculated for each of the systems. Very good agreement was obtained between dual-permeability representations of fracture networks and the fracture network when active porosity was used in the matrix elements.

Thermal response of the single fracture, the complete fracture network, and of the porous medium system were calculated. Thermal breakthrough in the single fracture case occurred after some 2000 days of injection while tracer breakthrough occurred within a few days. The rate of advance of the thermal front seems to be related to the active porosity of the system. If this is the case, then active porosity determined from tracer tests will be a useful tool in calculating thermal breakthrough.

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